Unconventional Natural Gas in the United States:

Production, Reserves, and Resource Potential (1991-1997)

Prepared for:
California Energy Commission

Contract No.:
300-97-011

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December 1, 1998

Summary

This study provides estimates of production, reserves, and resource potential of natural gas from "unconventional" resources in the continental United States. Three important types of unconventional gas resources contribute significantly to the nation's supply of natural gas: tight gas sands, gas shales, and coalbed methane. Analysis of data from state and operator sources shows that production and reserves have continued to climb during the 1990's as new production technologies have reduced the costs of developing these resources. Unconventional gas development has remained relatively strong despite low wellhead gas prices through 1996 and the expiration in 1992 of a tax credit supporting investment in these resources. Unconventional natural gas production totaled nearly 4.4 Tcf during 1997, accounting for about 23% of total U.S. gas production. The importance of unconventional natural gas sources within the overall gas supply of the U.S. is expected to continue its historical upward trend during the next several decades.

A new geology/engineering based unconventional gas forecasting model was developed by ARI (with DOE support) during 1998. We have updated our model and used it to forecast future production of unconventional gas in the U.S., based on a gas price forecast provided by the California Energy Commission (Energy Commission). The Energy Commission forecast envisions lower wellhead gas prices compared with other forecasts (such as the U.S. Department of Energy and the Gas Research Institute). Assuming "reference technology" development, we forecast that under the Energy Commission price forecast unconventional gas will fall slightly during the medium term, before recovering to about 4.4 Tcf during the year 2020, about equal to 1997 production levels.

California is a major end-user of unconventional gas production, because these resources are concentrated within the Rocky Mountain province. Unconventional gas will have an increasing impact over time in California, both by directly providing low-cost natural gas supplies as well as by indirectly impacting the price of other natural gas supplies.

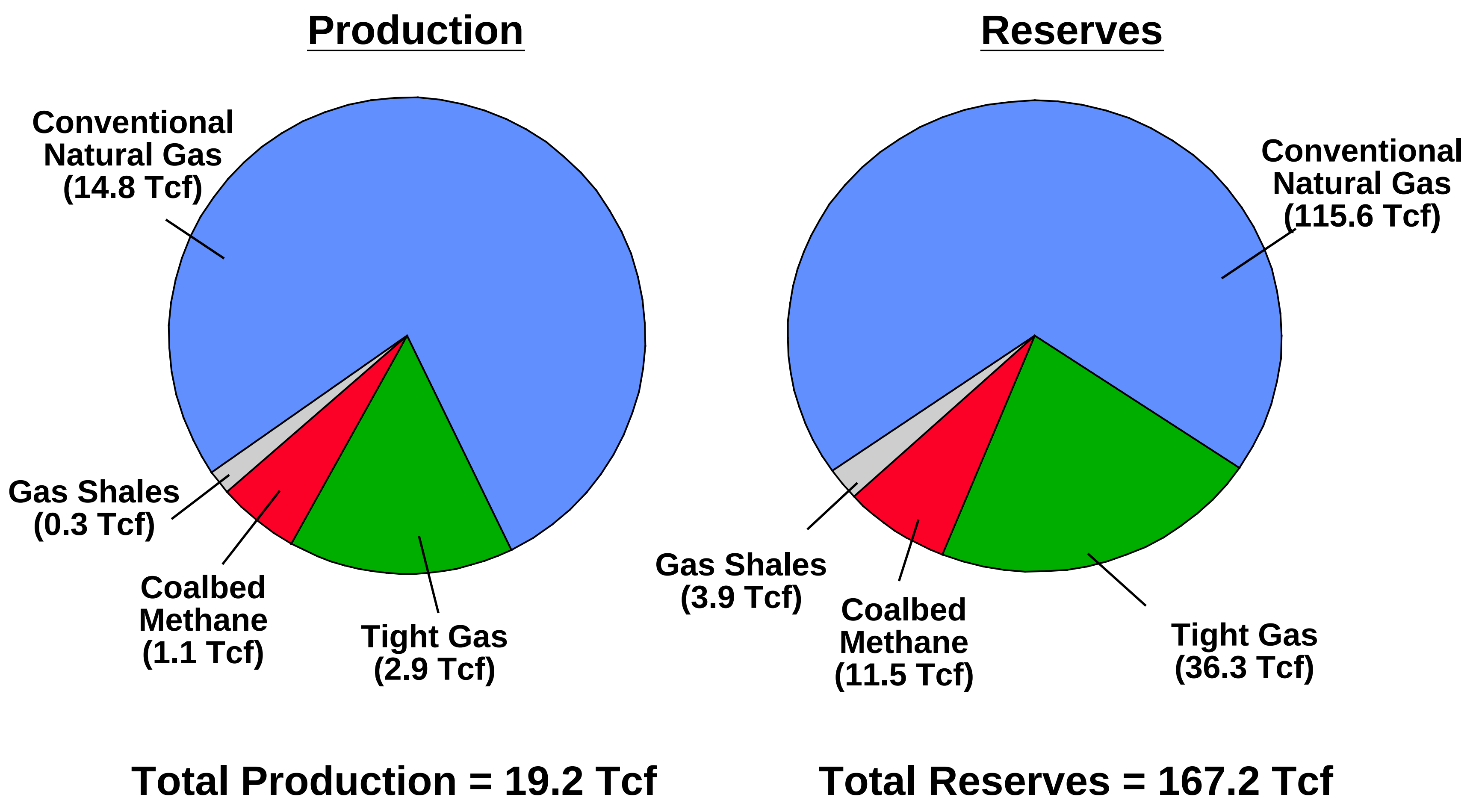
Abstract

During the past two decades, improved exploration and production technology in the oil & gas industry has led to significant levels of commercial production from a new class of natural gas resources -- collectively called "unconventional" natural gas. Formerly these natural gas resources-- including primarily tight gas sands, gas shale, and coalbed methane -- had been considered to be too costly to produce economically without tax supports because of their inherently low permeability. However, with improved extraction technology and additional investments in new wells, the importance of unconventional gas has grown steadily during this period. Today unconventional gas accounts for 23% of total U.S. natural gas production. Unconventional gas production

and new well completions have increased despite expiration of tax supports at year-end 1992.

An estimated 4.4 Tcf of unconventional natural gas was produced in the U.S. during 1997, out of a national total 19.21 Tcf of natural gas production (**figure 1**). Tight gas was the most productive unconventional gas resource at 2.9 Tcf, followed by coalbed methane (1.1 Tcf) and gas shale (0.3 Tcf). Year-end 1997 reserves of unconventional gas stood at an estimated 50.0 Tcf, including 35.7 Tcf of tight gas, 11.5 Tcf of coalbed methane, and 3.9 Tcf of gas shale. With continuing technological advances -- particularly improved reservoir characterization, and well siting, completion, and stimulation -- unconventional gas production is expected to increase in absolute and relative size during the next several decades. As California gas production stagnates or even continues to decline (0.29 Tcf in 1997, down 7% from 1994), unconventional gas -- particularly tight gas and coalbed methane -- produced in the Rocky Mountain basins will be an increasingly important source of natural gas supplies in the state.

Figure 1: Unconventional Gas Accounts for 23% of Total U.S. Natural Gas Production and 31% of Reserves



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Unconventional Natural Gas in the United States:

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1.0 Introduction

With natural gas production totaling 291 billion cubic feet (Bcf) in 1997, California must import nearly 85% of its natural gas supplies from outside the state. An increasing share of these gas imports is from a new type of natural gas production -- "unconventional" natural gas. This paper provides information on production, reserves and future development potential for unconventional natural gas in the U.S., in support of modeling efforts by the California Energy Commission to forecast the future availability of natural gas supplies in California.

The natural gas resource base in the United States is rich and varied. Most production of natural gas currently originates from sandstone or carbonate reservoirs that do not require extensive recovery procedures to elicit economic levels of productivity: these reservoirs are commonly referred to within the industry as "conventional" natural gas. Conventional gas reservoirs require a seal, as well as other favorable geologic conditions, to trap natural gas within a deposit of commercial size and quality. The challenge is to locate the trap; once drilled these reservoirs tend to produce their stored natural gas quite readily. However, given the maturity of the U.S. conventional natural gas resource base, most of the easy targets have already been developed. Exploration and development has increasingly focused on deep and/or offshore settings where costs and risks are high.

"Unconventional" natural gas, although compositionally similar (consisting essentially of methane and other light hydrocarbons), is stored and produced in distinctly different ways compared with conventional natural gas resources. Natural gas in unconventional gas deposits is generally stored quite uniformly within reservoirs that can extend over vast areas, rather than trapped in isolated anticlinal closures. Drilling depths to unconventional gas reservoirs often are quite shallow. Consequently, capital costs for these wells can be much less than for offshore fields. Large amounts of data typically exist constraining the size and distribution of unconventional natural gas deposits, thus discovery well rates can be high (>90%). However, the full commercial potential of unconventional natural gas has been slow to develop due to a number of serious reservoir and engineering challenges.

The first challenge for developing unconventional natural gas is to locate areas with favorable permeability, a reservoir property which enables the stored natural gas to be released and then flow into a producing well. Although stored gas content can be high, matrix permeability in unconventional natural gas reservoirs generally is extremely low, while fracture permeability may be somewhat higher but still quite low (1 md or far less). Under normal conditions, gas production rates from these low-permeability reservoirs are insufficient to pay back the capital investment for the well. However, advanced exploration technologies developed during the past decade can help to more reliably locate favorable naturally fractured reservoirs within low-stress settings, where unconventional reservoirs can be much more permeable (>1 millidarcy).

The second challenge for economically producing unconventional natural gas is an engineering one. Research by operators, the Gas Research Institute and others has led to new specialized well drilling, completion, and stimulation technologies, greatly improving the productivity of unconventional gas wells. Many of these technologies were developed during the 1980's and early 1990's when the industry benefited from a tax credit on unconventional natural gas production. Following expiration of this tax credit in 1992, continued technological advances have kept development costs low, sustaining the industry during a period of generally low wellhead natural gas prices.

This paper was prepared in preparation of testimony by the author at the 1998 California Energy Commission hearing concerning natural gas supply, price, and other issues related to the 1999 Fuels Report. The paper presents data on the unconventional natural gas industry in the U.S. during the period 1991 through 1997, including production, reserves, resource potential (by basin and by resource type). In addition, we provide a forecast of future U.S. unconventional gas production through the year 2020, using ARI's Model for Unconventional Gas Supply (MUGS). This information was updated from more detailed studies performed by the author and colleagues at Advanced Resources International, Inc. (ARI) and the U.S. Geological Survey (ARI, 1995; Kuuskraa and Stevens, 1995; Stevens et al., 1996, Reeves et al., 1996; Kuuskraa et al., 1996; Kuuskraa, 1998; Dyman et al., 1998; Kuuskraa et al., 1998; Kuuskraa and Schmoker, 1998).

Three principal resource types of unconventional natural gas are individually discussed within this paper:

Section 2.0	Tight Gas Sandstones
Section 3.0	Coalbed Methane
Section 4.0	Gas Shales.

Other unconventional natural gas resources, such as offshore gas hydrates, exist in vast deposits in the U.S. and other countries. However, these resources are characterized by inordinately high extraction costs using currently available technologies. Commercial production at current energy prices is not possible and these resources are unlikely to be economically viable during the next decade under even the highest gas price forecasts. These other unconventional natural gas resources are unlikely to make a significant contribution to U.S. gas supplies during the next two decades due to high development and production costs and, consequently, are not discussed here.

2.0 Tight Gas Sandstones

Natural gas stored in low-permeability sandstones has long been the most economically significant class of unconventional natural gas resources in the U.S. During the 1970's, operators developed large-scale hydraulic fracturing technology which boosted gas production from tight-gas reservoirs by ten-fold or more. Today, commercial production takes place in a total of 13 basins within the U.S. (**Map 1**). Annual gas production and proved reserves for the principal tight gas basins in the U.S. during the period 1991 to 1997 are summarized in **Table 1**.

Natural gas production from tight gas sands climbed to an estimated 2.9 Tcf during 1997, accounting for about 13% of total U.S. gas production. Because gas production from tight gas formations typically declines steeply after the first five years of production, most tight gas wells currently on line were drilled following the expiration of the Section 29 Unconventional Tax Credit. Proved reserves totaled 35.7 Tcf at beginning-of-year (BOY) 1998, up substantially from 29.2 Tcf in 1991.

Increased production in the Green River and Denver basins of the Rocky Mountain province, and the Lobo/Wilcox trend of East Texas have contributed to most of this recent growth. The Canyon sands of West Texas, the Lobo/Wilcox trend, and the Mesaverde of the Piceance basin have been hot spots of development and are expected to be active during the next several years.

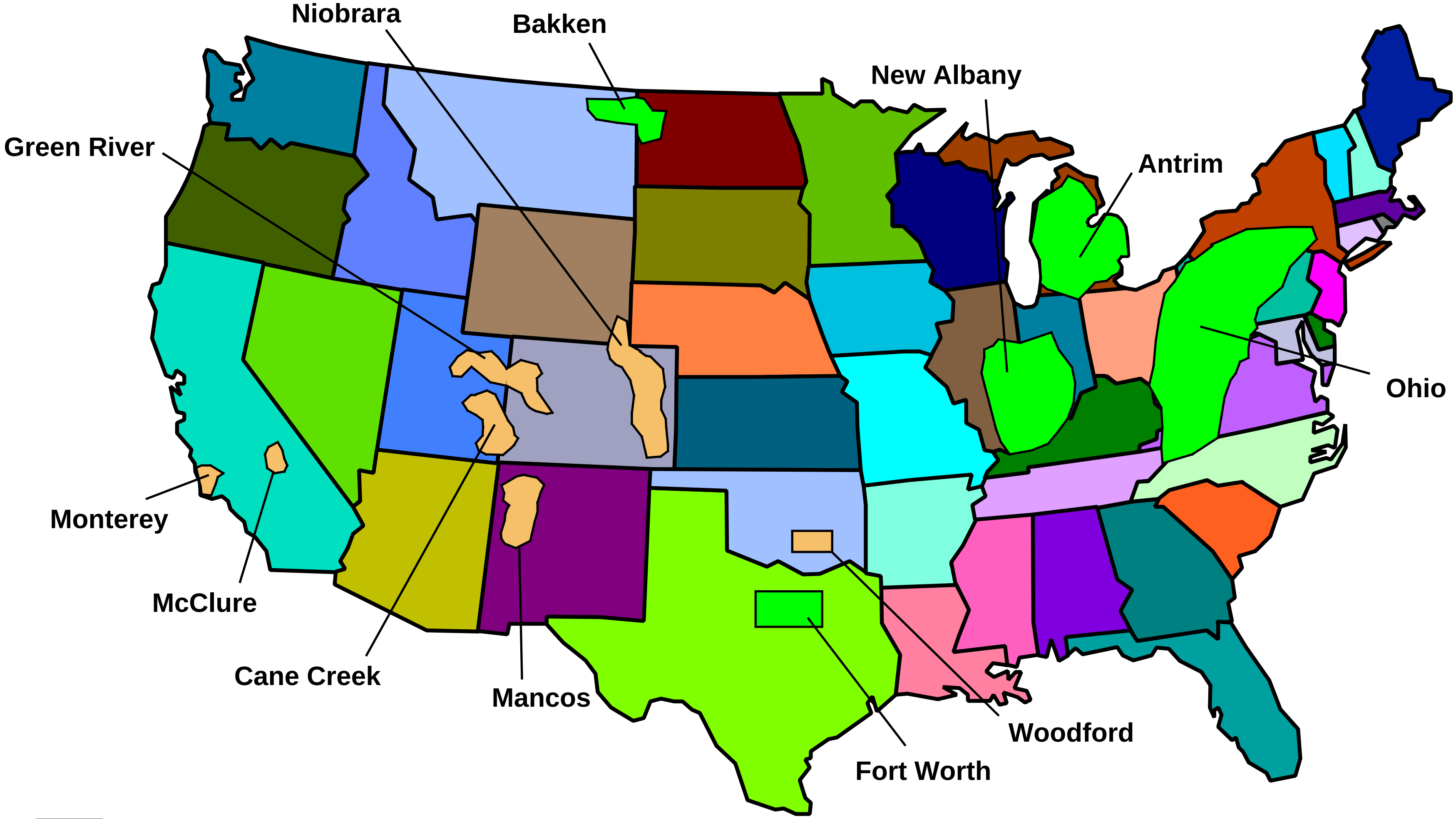
Wellhead gas prices have risen significantly in the Rocky Mountain province, traditionally one the lowest in the U.S. Wellhead prices averaged about $2.00/Mcf during 1998, nearly double the $1.00 to $1.10/Mcf that was common during the mid-1990’s. Higher prices, along with improved extraction technologies, have led to sharply accelerated development of tight gas resources in the Rockies.

Both integrated major oil companies and small independents have been active in tight gas development. Much of the current tight gas activity is in rediscovered plays, where advanced well siting technologies employing remote sensing have helped locate more permeable areas and better well drilling and stimulation practices have improved recovery.

Tight gas production is an important gas supply source for the state of California, with significant gas production from the Green River, Piceance, San Juan and other Rocky Mountain basins transported into the state via pipeline. Furthermore, the importance of tight gas supplies for California is expected to increase in the future.

2.1 Appalachian Basin. The birthplace for tight gas development was the Appalachian basin, and tight gas remains the principal target in this mature region. During 1997, estimated tight gas production in this basin totaled about 400 Bcf, essentially

U.S. Gas Shale Basins



Basins where GRI has conducted R&D programs

Basins where productive shales are present

Table 1

Tight Gas Sands
All numbers in Bcf; Reserve #'s - BOY

ARKLA BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	51	48	51	52	50	50	52	
Reserves	400	344	380	420	460	500	600	600

EAST TEXAS

	1991	1992	1993	1994	1995	1996	1997	1998
Production	360	339	365	370	370	370	390	
Reserves	3500	3390	3500	3750	4000	4200	4500	4500

TEXAS GULF COAST

	1991	1992	1993	1994	1995	1996	1997	1998
Production	461	435	468	474	500	520	555	
Reserves	2700	2627	2980	3165	3320	3250	3450	3600

WIND RIVER BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	11	11	11	11	20	30	40	
Reserves	180	178	200	250	300	450	510	600

GREEN RIVER BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	200	231	295	335	327	360	390	
Reserves	3200	3198	3500	3600	3700	5400	5500	6000

DENVER BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	75	71	76	77	75	75	75	
Reserves	1000	1194	1150	1100	1050	1000	1050	900

UINTA BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	24	35	66	59	56	60	60	
Reserves	175	225	400	500	600	510	536	740

PICEANCE BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	33	31	33	34	32	40	50	
Reserves	300	516	600	700	800	900	980	1070

Table 1

Tight Gas Sands

All numbers in Bcf; Reserve #'s - BOY

ANADARKO BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	226	213	230	232	220	220	220	
Reserves	1800	1841	1900	2000	2100	2280	2220	2280

PERMIAN BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	248	235	253	255	260	260	280	
Reserves	2600	2544	2430	2370	2315	2600	2800	2800

SAN JUAN BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	298	321	350	342	330	340	450	
Reserves	8910	10130	7840	7660	7640	8800	8860	8150

WILLISTON BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	8	8	8	10	15	20	21	
Reserves	80	101	150	200	250	300	300	300

APPALACHIAN BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	389	419	396	396	390	400	400	
Reserves	4451	4785	4440	4350	5040	4500	4723	4730

TOTALS - ALL BASINS

	1991	1992	1993	1994	1995	1996	1997	1998
Production	**2384**	**2397**	**2602**	**2647**	**2645**	**2745**	**2983**	
Reserves	**29296**	**31073**	**29470**	**30065**	**31575**	**34690**	**36029**	**36270**

unchanged from the long-term 1990's average. With a total of about 85,000 wells on line, individual well productivity in this basin tends to be quite low, averaging less than 13 thousand cubic feet per day per well (Mcfd/well).

Two tight gas plays within the Appalachian basin are of particular importance. First, the Oriskany play of southern Pennsylvania and northern West Virginia is experiencing a resurgence, with new stimulation technology boosting per-well reserves by 50% to 1-2 Bcf. Second, the Clinton/Medina play in Ohio and western Pennsylvania has become over-mature: with per-well reserves dropping to 0.1 Bcf/well, this play is economically marginal even with low drilling/completion costs of $110,000/well. Overall, tight gas production in the highly mature Appalachian basin is expected to hold steady or even decline below 400 Bcf/year, even though this area benefits from some of the nation's highest wellhead prices for natural gas ($2-2.50/Mcf).

2.2 San Juan Basin. Located in northern New Mexico and southern Colorado, this was the first western U.S. basin to produce gas from tight sand formations. Development of Mesaverde tight sands peaked by 1981 and declined steadily since. Tight sand formations in the San Juan basin have an unusually high reserves/production ratio of approximately 20, reflecting aggressive booking of reserves by operators. Increased infill drilling on tighter well spacing has helped to increase production to about 450 Bcf during 1997. Reserves at BOY 1998 are estimated to be about 8.2 Tcf.

2.3 Green River Basin. The most important emerging basin for tight gas in the U.S., with 213 Tcf of technically recoverable tight gas estimated by the USGS (1995), the Greater Green River basin is expected to account for much of the long-term future growth in tight gas. Located in southwestern Wyoming, the primary producing formations in the basin are the Frontier and Mesaverde sandstones, but the Dakota sand is also significant. Production, drilling, and reserves of tight gas all have grown following expiration of the tax credit in 1992, demonstrating that this basin has staying power. Production during 1997 totaled approximately 390 Bcf, with an estimated 6.0 Tcf of tight gas reserves at BOY 1998. Wells in the basin are deep (9,000-11,000 ft) and costly ($0.5 to 1.0 million) to drill, complete, and stimulate. However, with per-well reserves of 2-3 Bcf, the play is economic at current gas price conditions ($1.50-2.00/Mcf).

2.4 Wind River Basin

The Wind River tight gas basin has enormous potential, but remains largely undeveloped. Following an initial flurry of activity during the early 1980's, the play remained largely dormant until some drilling resumed in 1994. Mesaverde, Fort Union, and Frontier Formations are the primary targets. Tight gas production from the Wind River basin has grown modestly during the past four years, reaching an estimated 40 Bcf during 1997, and is expected to continue to increase during the next five years. Reserves at BOY 1998 are estimated at 0.6 Tcf.

2.5 Uinta Basin. Drilling in the southeastern Utah's Uinta basin has focused on the Wasatch formation in the Natural Buttes field. Production of tight gas totaled 56 Bcf during 1997, with BOY 1998 reserves up sharply over the previous year at 0.7 Tcf. Production is expected to increase moderately during the next five years.

2.6 Piceance Basin. Improved well siting technology using remote sensing and geophysics, restimulation of poorly completed wells using best practices, and uphole recompletion of bypassed zones has revived gas production from the Mesaverde tight sandstones in the Piceance basin, located in western Colorado and eastern Utah. Infill drilling on 40-acre spacing, down from 160 acres several years ago, also provides opportunities for adding significant reserves. Tight gas production totaled 50 Bcf during 1997, with an estimated 1.1 Tcf of reserves at BOY 1998.

2.7 Denver Basin. Development here has been concentrated at Wattenberg field, which has ranked as one of the most active fields in the U.S. (well completions) during the past three years. Although production has held steady at about 75 Bcf/year for the past four years, significant potential -- estimated at nearly 5 Tcf -- remains in the basin. Reserves at BOY 1998 are estimated to be down slightly at 0.9 Tcf.

2.8 East Texas/Arkoma Basins. The Cotton Valley and Travis Peak Formations are the main tight gas reservoirs in this area. Gas production totaled about 390 Bcf during 1997, with an estimated 4.5 Tcf of reserves at BOY 1998. With improved hydraulic stimulation well technology, supported by R&D by the Gas Research Institute, production from this play is expected to continue to increase.

2.9 Texas Gulf Coast. The Lower Wilcox/Lobo trend along the Gulf Coast is the principal tight gas play in this region, with over 4 Tcf of production since development began in 1973. Currently, over 2,000 wells are producing about 555 Bcf/year, and new completions are steadily increasing. With well costs down to about $750,000, per-well reserves averaging 2.5 to 3.0 Bcf, and favorable wellhead gas prices, this play has remained quite active during the past several years. Reserves at BOY 1998 reached an estimated 3.6 Tcf.

2.10 Anadarko. The principal tight gas play in the Anadarko basin is the Pennsylvanian-aged Cherokee Group sandstones. Production zones in this basin are unusually deep (12,000 to 13,000 feet), but drilling costs have dropped by 50% since the early 1990's due to excess rig capacity and to improved drilling productivity. Furthermore, gas productivity during this period has grown to an average 1.2 MMcfd/well from 0.8 MMcfd/well. Consequently, this play has remained active following the 1992 expiration of the tax credit, with production fairly stable at about 220 Bcf. This play was not assessed by the 1995 USGS National Assessment; earlier assessments by the National Petroleum Council put technically recoverable resources at approximately 4-6 Tcf. Estimated reserves at BOY 1998 stood at 2.1 Tcf.

2.11 Other Basins. Significant tight gas development also is taking place in the Arkla, Permian, and Williston basins. Production and reserves for these basins are listed in Table 1.

3.0 Coalbed Methane

For centuries, methane stored in deep coal seams has presented a hazard to coal miners. However, specialized production technologies developed since the 1970's has enabled natural gas operators to commercially produce coalbed methane. Most coalbed methane production currently takes place in virgin coal seams far from active or past coal mining. However, in the Warrior and Appalachian basins in the eastern U.S., coalbed methane production removes hazardous methane from coal seams scheduled to be mined in the near future, with the added benefit of improving coal mining safety and productivity.

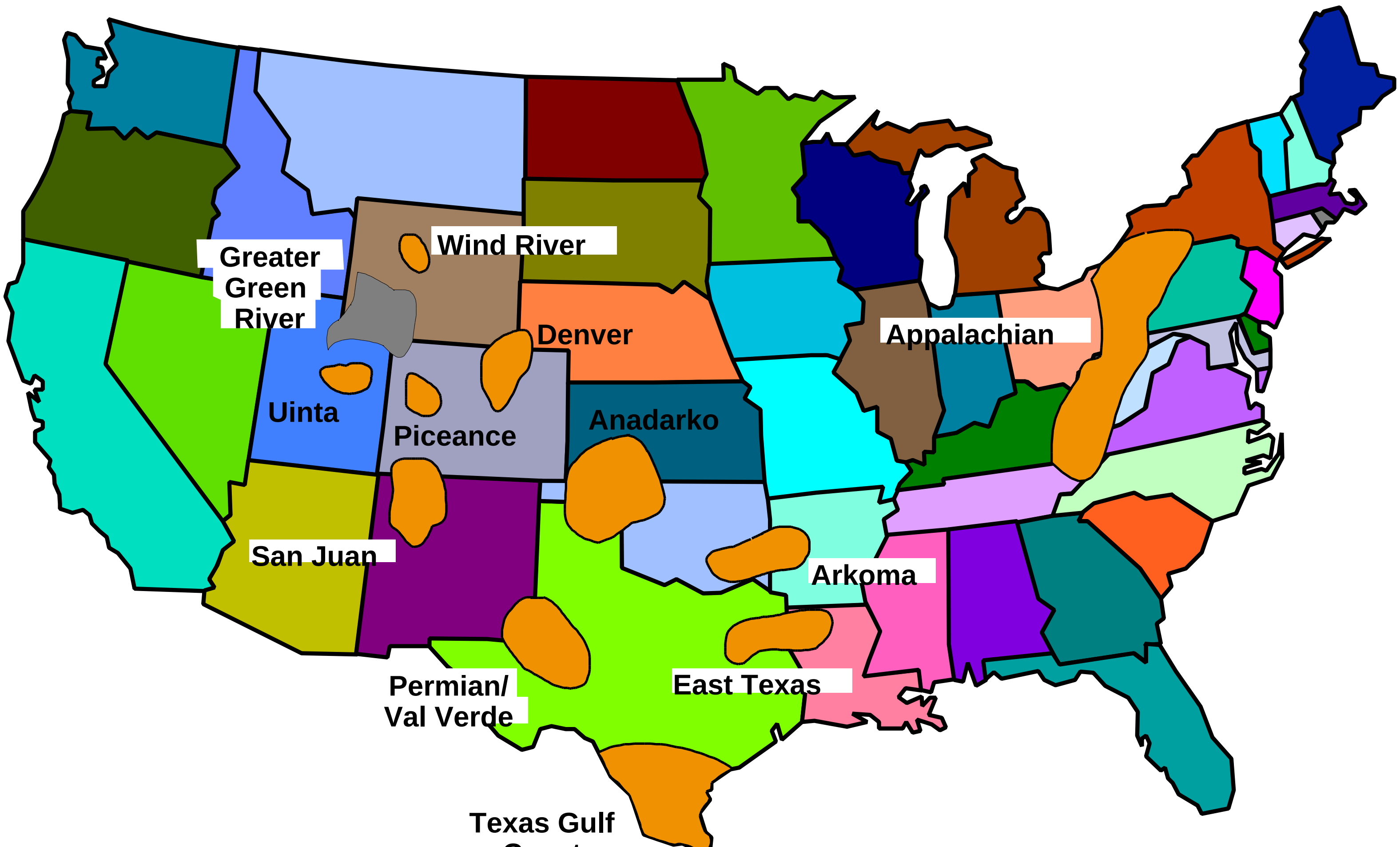
An estimated total of more than $5 billion in capital investments, along with continued technological improvements, have built an entirely new coalbed methane (CBM) industry within the U.S. during the past two decades. Today, operators are active exploring coal basins overseas in Australia, China, Poland, South Africa, India and other countries for new CBM areas. During 1997, an estimated total of 1.1 Tcf of coalbed methane was produced in the U.S., accounting for about 6% of total U.S. natural gas production. CBM reserves at BOY 1998 stood at 11.5 Tcf, some 7% of total natural gas reserves in the U.S. A cumulative total of 18 Tcf of proven CBM reserves have been booked in the U.S., mostly during the 1990’s.

Although significant CBM resources exist in a dozen U.S. coal basins (**Map 2**), more than 90% of CBM production still is concentrated in just two basins: the Black Warrior basin in Alabama and the San Juan basin in southern Colorado and northern New Mexico (**Table 2**). Other basins currently producing CBM include the Uinta, Raton, Central Appalachian, Powder River, Arkoma, and Cherokee basins. The Uinta basin in Utah will be the most important emerging CBM basin during the next 5-10 years; a 2-year delay for environmental review by the BLM is nearly over; The Raton basin is also very promising, with 100 new wells online. Other basins, such as the Greater Green River and Piceance basins, hold enormous CBM resource potential, but commercial development has not been successful there to date due to unfavorable reservoir conditions.

New production technologies, such as enhanced coalbed methane recovery using nitrogen or carbon dioxide injection, are expected to boost CBM production in the future (Stevens et al., 1998).

Most of the CBM production in the San Juan basin (about 2.5 Bcfd) is currently transported by pipeline to southern California, where it is an important supply source of natural gas for the region. Future CBM development in the San Juan and other Rocky Mountain basins will directly affect the outlook for gas supplies in this high-demand region of California.

U.S. Tight Gas Basins



Coalbed Methane - U.S. Basins

All numbers in Bcf; Reserve #'s - BOY

Table 2

SAN JUAN BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	277	450	612	706	795	858	918	
Reserves	3804	6240	7386	7820	6992	7604	7557	7831

CENTRAL APPALACHIAN BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	1	11	20	28	31	34	40	
Reserves	132	352	506	810	1132	1130	1172	1414

WARRIOR BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	68	92	105	108	109	110	111	
Reserves	1224	1714	1768	1237	976	972	823	1077

RATON BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	0	0	0	0	2	5	12	
Reserves	0	0	0	0	40	100	280	360

POWDER RIVER BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	1	1	1	2	4	8	13	
Reserves	17	20	40	60	60	100	150	180

UINTA BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	0	0	1	5	12	17	23	
Reserves	0	20	30	240	371	400	400	420

PICEANCE BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	5	5	4	3	3	4	3	
Reserves	26	42	54	62	58	56	54	50

GREEN RIVER BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	0	0	0	0	0	0	0	
Reserves	0	0	0	0	0	0	0	0

CHEROKEE BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	2	3	3	3	3	2	2	
Reserves	23	42	49	70	70	71	70	70

ARKOMA BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	0	0	2	3	4	3	3	
Reserves	2	4	8	40	57	59	60	60

TOTALS - ALL BASINS

	1991	1992	1993	1994	1995	1996	1997	1998
Production	**354**	**562**	**748**	**858**	**963**	**1040**	**1125**	
Reserves	**5228**	**8434**	**9841**	**10339**	**9756**	**10492**	**10566**	**11462**

3.1 Black Warrior Basin. Because large-scale commercial production was first established here by coal mine degasification projects during the 1970's, this basin is considered to be the birthplace of the CBM industry. Drilling was most active during the late 1980's and early 1990's at a pace of several hundred new well completions per year. However, individual well productivity is relatively low in the Warrior basin, averaging about 120 Mcfd/well, and development economics are generally marginal even with relatively high wellhead gas prices. Development has slowed markedly since the expiration of the tax credit. Further development is likely to continue to slow, with maturing of the better areas within the basin and marginal economics under current gas prices.

Some potential exists in the Warrior basin for recompletion of wells that were poorly stimulated during the haste to qualify for the tax credit, but production is expected to peak at approximately 111 Bcf in 1997, and then decline gradually as the number of producing wells falls by about 100 wells per year due to abandonment. Much of the 3.4 Tcf of technically recoverable CBM resources estimated by the USGS (1995) occurs primarily within low-permeability, thin-seam settings; further development of this remaining CBM resource will require additional technological advances and/or higher wellhead gas prices. BOY 1998 reserves stood at 1.1 Tcf.

3.2 San Juan Basin. Since the mid-1980's, the San Juan has dominated the CBM industry, with frequently stellar per-well productivity and low finding/development costs. During 1997, CBM production in the San Juan basin totaled 918 Bcf from over 3,000 producing wells, for an average of more than 800 Mcfd/well – about 7-fold higher than the productivity of Warrior basin CBM wells. Production in the high-productivity "Fairway" averages even higher, 2 to 3 million cubic feet per day (MMcfd) per well.

With its high-productivity wells, the San Juan currently accounts for over 80% of total CBM production. However, many of the best areas have already been drilled, and most future reserve additions are likely to come from recompletions -- particularly highly productive cavity completions, which can outperform fracced completions by 5-10 fold in favorable settings. Enhanced recovery of CBM using nitrogen or CO_2 flooding, undergoing pilot commercial testing by Amoco and Burlington Resources, respectively, has the potential to add several Tcf of reserves or more from existing producing properties in the basin.

CBM production in the San Juan is likely to peak at nearly 1 Tcf/year during the late 1990's, and then remain significantly above 500 Bcf for the following decade. Given that an additional in-place resource estimated at 60 to 80 Tcf is present within coal seams in the San Juan and that enhanced CBM recovery technology was not considered by the USGS, ARI considers the USGS estimate of 9.7 Tcf of technically recoverable resources to be highly conservative.

3.3 Central Appalachian Basin. Currently, this is the third most productive CBM basin, with a total of about 40 Bcf of gas produced during 1997. Development here has taken place largely in conjunction with coal mining: fracced wells, gob wells, as well as unstimulated vertical degasification boreholes are used to produce CBM close to actively mined areas. Favorable gas prices of $2.50/Mcf in this northeastern U.S. location also have stimulated development.

To date, CBM development in the Central Appalachian basin has been concentrated in Virginia, owing to the passage in 1991 of a state law specifying CBM ownership and administration. Although West Virginia’s portion of the resource is less favorable, passage in 1995 of a similar law in West Virginia is finally expected to set the legal foundation for CBM development there in the future. However, the Central Appalachian basin is limited in size, and most of the 4.6 Tcf of technically recoverable resources estimated by the USGS is located in unfavorable (thin coal) areas that are unlikely to be developed. Total annual CBM production from the Central Appalachian basin will probably remain below 50 Bcf during the next decade.

3.4 Uinta Basin. With favorable reservoir conditions, this basin is the first area likely to approach the high productivity achieved in the San Juan basin. Significant commercial CBM development has taken place in the Uinta basin only since 1994, with one highly successful (but still small) field. Per-well productivity is increasing past 500 Mcfd/well as these wells dewater. Given low well costs totaling only $250,000 (half that of the San Juan), this basin is poised for rapid development, particularly now that a much delayed BLM land use and environmental review has concluded. Operators Texaco and River Gas have announced firm plans to drill 100 wells/year during the next decade, which would add 2 Tcf in new CBM reserves and dramatically increase gas production over the 23 Bcf achieved in 1997.

The 1995 USGS resource assessment of CBM in the Uinta basin considered only the less productive Blackhawk coals that were the early (and unsuccessful) target of CBM operators, rather than the younger Ferron coals that have been so successful at the River Gas/Texaco development and are likely to be the primary target for future CBM development. No rigorous assessment has been performed to estimate technically recoverable resources from the Ferron, however, based on operator information ARI estimates that approximately 5 Tcf of gas may be recoverable in the basin using existing technology.

3.5 Raton Basin. Located in northern New Mexico and southern Colorado, the Raton basin now has its first successful commercial CBM development. Until recently, the lack of a natural gas pipeline infrastructure had slowed development in the Raton basin. However, a new 20-mi long pipeline into the best portion of the basin enabled commercial production to commence during 1995. CBM production totaled 12 Bcf during 1997, with BOY 1998 reserves at 360 Bcf. Evergreen Resources has the most successful development, with 75 wells averaging 350 Mcfd/well. Coal seam gas production in the Raton basin is forecasted to grow rapidly during the next 10 years.

3.6 Piceance Basin. Although CBM development began relatively early in this basin, production actually peaked in 1992 at about 6 Bcf and has since declined due to unfavorable reservoir conditions in this large but problematic basin. CBM production during 1997 totaled just 3 Bcf, from 50 Bcf of gas reserves. Low permeability in deep Mesaverde coal seams causes low well productivity (100 Mcfd/well), insufficient for economic viability in this deep, high-cost setting. The USGS estimate of 10.1 Tcf in technically recoverable CBM resources would seem to be optimistic unless significant advances occur in completing and stimulating the deep coal seams in the Piceance basin.

3.7 Powder River Basin. Per-well productivity is low in this shallow, low-rank setting – currently averaging 130 Mcfd/well -- but well costs are also extremely low. Independent operators have drilled several hundred CBM wells in the Wyoming portion of the basin, which produced a total of approximately 13 Bcf during 1997, up sharply during the past few years. CBM reserves are also up significantly, standing at 180 Bcf at BOY 1998. The USGS estimate of 2.9 Tcf of technically recoverable CBM resources, out of a total in-place resource of over 30 Tcf in the Powder River basin, would appear to be within reach.

3.8 Other CBM Basins. A massive CBM resource exists in the Greater Green River basin, but development there has failed due to undersaturated reservoir conditions and excessively high water production. The mid-continent coal region comprises several shallow, low-rank coal basins that have experienced a limited amount of CBM development during the past five years. Productivity in these basins tends to be low (50 Mcfd/well), due to thin coal seams and low gas content, thus activity has primarily been limited to low-cost independent operators. The Arkoma and Cherokee basins have experienced a considerable amount of CBM well completion activity following the expiration of the tax credit, as operators learned to minimize development costs in this area of moderately high wellhead gas prices. Production in each of these basins has grown gradually, reaching an estimated 5 Bcf during 1997, but is unlikely to increase sharply under prevailing gas price scenarios.

4.0 Gas Shales

Gas shales were the first unconventional gas resource to be commercially developed, with well completions occurring in the Appalachian basin as early as the late 19th century. However, development has lagged that of tight gas and coalbed methane, so that gas shales today is the smallest unconventional resource in terms of production and reserves. Nevertheless, development has accelerated during the 1990's, and is expected to continue at a healthy pace in several basins during the next ten years or longer.

Gas shales production totaled an estimated 320 Bcf during 1997, more than double the 1991 production level of 156 Bcf, and accounting for about 2% of total U.S. natural gas production (**Table 3**). Reserves of gas shales also grew rapidly to 3.9 Tcf at BOY 1998, up from just 1.6 Tcf at BOY 1991. Development has been concentrated within two basins: the mature but low-productivity Appalachian basin and the newcomer powerhouse Michigan basin (**Map 3**). The Fort Worth basin is also experiencing significant gas shales development.

Advanced drilling, completion, stimulation, and operating technologies have greatly improved the productivity and development economics of gas shale resources. The play remains the province of low-cost independent operators, however, with relatively minor activity by the major oil companies.

California currently does not receive significant gas supplies from gas shale formations. Although it is unlikely that California will directly import significant quantities of gas shale production during the next two decades, projected development of gas shale resources in the U.S. indicates that they will significantly affect natural gas markets on a national and regional level, including gas markets in California.

4.1 Appalachian Basin

Over 20,000 gas wells have been completed in the Devonian-age shales of the Appalachian basin, with an estimated total of 100 Bcf of gas during 1997. (Information on development activity in this basin is difficult to obtain, because each of the six individual states covering the basin have varying and often minimal operator reporting requirements.) Historical development has concentrated on western West Virginia, eastern Ohio, and northeastern Kentucky. However, most of the recent activity has centered around Pike County, Kentucky in the Big Sandy field.

Unlike the improvements seen in other gas shale basins from application of advanced technology, gas productivity of more recent shale wells in the Appalachian basin has significantly declined within highly mature areas. Future development will have to locate new undrilled areas with adequate gas content and permeability. The USGS

Table 3

Gas Shales

All numbers in Bcf; Reserve #'s - BOY

MICHIGAN BASIN (Antrim Shale)

	1991	1992	1993	1994	1995	1996	1997	1998
Production	55	75	97	128	157	170	190	
Reserves	389	535	937	1007	1151	1500	1680	1800

APPALACHIAN BASIN (Devonian Shale)

	1991	1992	1993	1994	1995	1996	1997	1998
Production	94	101	107	103	101	106	100	
Reserves	1170	1433	1361	1379	1743	1700	1800	1800

FORT WORTH BASIN (Barnett Shale)

	1991	1992	1993	1994	1995	1996	1997	1998
Production	6	7	11	14	20	25	30	
Reserves	50	60	68	120	178	208	270	300

ILLINOIS BASIN

	1991	1992	1993	1994	1995	1996	1997	1998
Production	NA	NA	NA	NA	NA	NA	NA	
Reserves	NA	NA	NA	NA	NA	NA	NA	NA

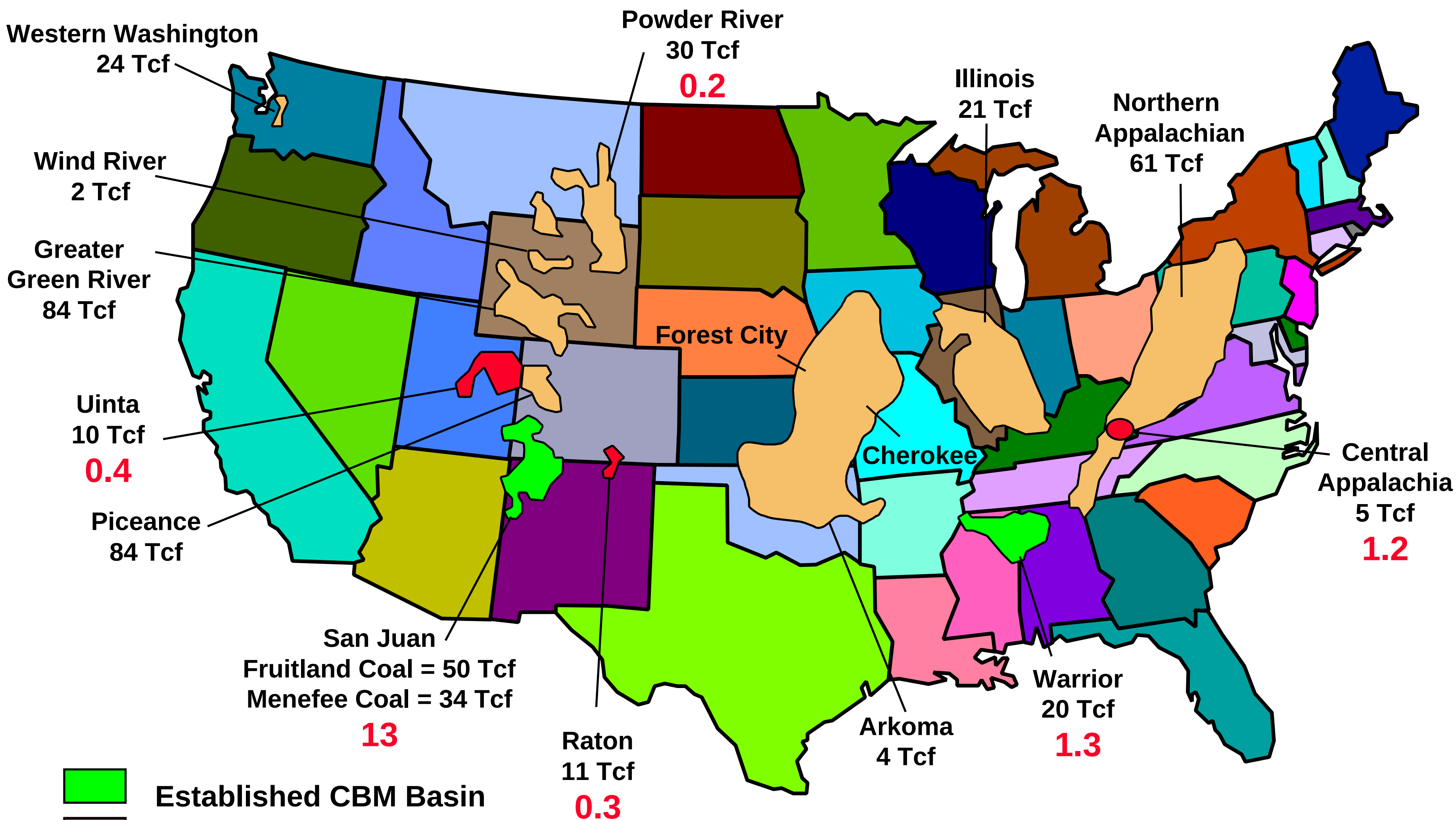
TOTALS - ALL BASINS

	1991	1992	1993	1994	1995	1996	1997	1998
Production	**156**	**182**	**215**	**245**	**278**	**301**	**320**	
Reserves	**1609**	**2028**	**2366**	**2506**	**3072**	**3408**	**3750**	**3900**

TOTAL - ALL UNCONVENTIONAL GAS (COALBED METHANE, GAS SHALES, TGS)

	1991	1992	1993	1994	1995	1996	1997	1998
Production	**2893**	**3141**	**3565**	**3750**	**3885**	**4087**	**4428**	
Reserves	**36133**	**41535**	**41677**	**42910**	**44403**	**48590**	**50345**	**51632**

U.S. Coalbed Methane Basins



Established CBM Basin

Emerging CBM Basin

Frontier CBM Basin

13 Reserve Additions (Tcf)

JAF00578.PPT

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estimates sizeable technically recoverable resources from gas shale reservoirs in the Appalachian basin, but only a fraction of this resource is likely to be converted to proved reserves under current wellhead gas prices. Production from gas shales is likely to stabilize at the current level of about 100 Bcf during the next 5 to 10 years, unless gas prices change signficantly.

4.2 Michigan Basin

The Antrim Shale of the Michigan basin has recently become the most important gas shale play, as well as one of the most active natural gas plays in the U.S. During 1992, the Antrim accounted for nearly 15% of all gas completions in the U.S., as operators rushed to qualify for Section 29 tax credits. While activity slowed somewhat in 1993, completions were up again after 1995 as operators realized that the play remained economic without tax supports and opened up new areas within the basin.

Gas shale production in the Michigan basin totaled 190 Bcf in 1997, more than triple 1991 levels. Reserves stood at 1.8 Tcf at BOY 1998, up almost 5-fold over 1991.

The Michigan basin is likely to continue as the most active gas shales play, and production is likely to continue to increase well beyond 200 Bcf/year during the next five years, as the northern development expands and new fields are developed in the southern and western portions of the basin. Only about 2 Tcf of reserve additions have taken place to date, out of a total technically recoverable resource estimated at 42.6 Tcf (USGS, 1995). Given the favorable wellhead gas prices in this basin, at about $2.50/Mcf some of the highest for any unconventional gas play, it is likely that several Tcf of reserves or more could be added during the next decade; production could easily double from current levels.

4.3 Fort Worth Basin

The Barnett Shale of the Fort Worth basin in north-central Texas is a new gas shale play, with significant development taking place only since 1990. The Barnett play is relatively deep compared with other gas shale basins, averaging 7,000-8,000 feet, and investment costs are considerably higher, totaling $700,000 to drill, hydraulically stimulate and complete one well. However, well productivity has also been much higher, averaging over 500 Mcfd/well with reserves estimated at over 1 Bcf/well.

A single operator, Mitchell Energy & Development, has accounted for over 90% of Barnett Shale completions, and has accelerated drilling during the past several years. Gas production during 1997 totaled 30 Bcf, and is projected to continue to increase during the next five years. Reserves at BOY 1998 stood at 300 Bcf.

The USGS did not originally include the Barnett Shale in their 1995 national assessment. However, preliminary work conducted jointly by the USGS and ARI shows that approximately 10 Tcf of technically recoverable gas resources may be present in this play (Kuuskraa et al., 1998).

5.0 Forecasted Production (1998-2020)

ARI performed a projection of unconventional natural gas production to the year 2020, using our Model for Unconventional Gas Supply (MUGS) and a gas price forecast provided by the California Energy Commission. The MUGS model design is described in documentation available from the U.S. Department of Energy. The Energy Commission gas price forecast (**Table 4**) envisions lower natural gas prices compared with forecasts prepared for the same time period by the U.S. Department of Energy, Energy Information Administration and the Gas Research Institute. This low gas price track is expected to lead to stagnant or even declining levels of unconventional gas production and reserves in the United States.

Our forecast of unconventional natural gas production to the year 2020 is summarized in **Tables 5, 6, and 7** (for coalbed methane, tight gas, and gas shale, respectively). We forecast coalbed methane production to peak in 1998 at 1.196 Tcf, but then decline steadily to about 0.866 Tcf in 2011 and then recover only slightly to 0.897 Tcf in 2017. Likewise, tight gas production is forecast to peak in 1998 at 3.102 Tcf, and then decline to 2.230 Tcf in 2008, recovering strongly to 3.180 Tcf by 2020 as advanced recovery technology begins to have an impact. Gas shale production peaks in 1999 at 0.347 Tcf, declining to 0.292 Tcf by 2008, and then steadily increases under the effects of improved technology to 0.385 Tcf by 2020.

Technological progress has a profound impact on the development economics of unconventional natural gas. The reference technology case assumes early 1990's levels of investment in R&D for unconventional gas. We also performed sensitivity to technological progress, including a high technology case based on stronger R&D investments in gas extraction technologies, such as occurred during the 1980's. Finally, a low technology case was run based on extrapolating the current very low investment on unconventional gas R&D. As shown in **Figure 2**, these alternate scenarios of technological progress have a significant impact on future gas production.

Overall, unconventional gas production (Energy Commission price track, base technology) is forecast to dip slightly during the first decade of the next century, but then to recover to about the current level of 4.4 Tcf by the year 2020. Unconventional gas development is quite sensitive to wellhead natural gas prices; even slightly higher prices would lead to substantially higher production from this resource.

Table 4

Califiornia Energy Commission U.S. Wellhead Gas Price Track

1994	1.5		1.5
1995	1.51		
1996	2.17	*	
1997	2.23	*	
1998	1.93	*	
1999	1.55		1.55
2000	1.582		
2001	1.614		
2002	1.646		
2003	1.678		
2004	1.71		1.71
2005	1.738		
2006	1.766		
2007	1.794		
2008	1.822		
2009	1.85		1.85
2010	1.874		
2011	1.898		
2012	1.922		
2013	1.946		
2014	1.97		1.97
2015	1.986		
2016	2.002		
2017	2.018		
2018	2.034		
2019	2.05		2.05
2020	2.06		
2021	2.07		
2022	2.08		
2023	2.09		
2024	2.1		2.1
2025	2.108		
2026	2.116		
2027	2.124		
2028	2.132		
2029	2.14		2.14
2030	2.145		
2031	2.15		
2032	2.155		
2033	2.16		
2034	2.165		
2035	2.17		
2036	2.175		
2037	2.18		
2038	2.185		
2039	2.19		2.19

* Historical average wellhead price data (used in analysis)

Table 5: Coalbed Methane Production Forecast (Reference Technology, CEC Price Track)

Summary Table -- Reference Case

	Tech Recov. Wells	Undev. Resc. (Bcf)	Ult Recov.	Resv. + Prod.	Econ. Undevel. Resour.	Undevel. Wells	Proved Resv. (Bcf)	Prod. (Bcf)	New Wells
Base Case	90,122	55,198	69,253	14,055	19,738	10,725	10,499	1,040	400
1997	89,722	54,355	69,516	15,160	19,986	10,713	10,564	1,127	389
1998	89,332	53,746	70,927	17,181	18,110	11,337	11,458	1,196	323
1999	89,009	53,220	71,490	18,270	11,827	4,188	11,352	1,184	98
2000	90,019	53,920	72,833	18,913	11,594	4,103	10,810	1,128	96
2001	90,364	54,084	73,620	19,537	12,685	5,900	10,307	1,078	142
2002	90,663	54,221	74,397	20,176	13,539	6,321	9,867	1,030	153
2003	90,951	54,339	75,162	20,824	13,314	6,188	9,485	991	150
2004	91,241	54,462	75,916	21,454	14,277	7,953	9,124	958	195
2005	91,487	54,562	76,659	22,097	14,041	7,783	8,809	922	205
2006	91,723	54,633	77,389	22,757	15,755	10,350	8,546	893	292
2007	91,872	54,475	78,105	23,630	15,983	11,575	8,526	893	314
2008	91,999	54,330	78,806	24,476	14,783	9,850	8,479	892	277
2009	92,193	54,267	79,511	25,244	16,263	10,930	8,355	883	310
2010	92,324	54,145	80,187	26,042	15,864	10,663	8,270	875	302
2011	92,462	56,595	83,402	26,807	16,652	8,557	8,161	866	301
2012	92,906	56,521	84,207	27,686	17,059	9,794	8,174	870	329
2013	93,018	56,299	84,860	28,560	17,246	9,745	8,178	874	331
2014	93,127	56,068	85,495	29,427	16,817	9,463	8,170	877	331
2015	93,237	59,530	89,812	30,282	17,945	9,412	8,149	881	331
2016	93,346	59,286	90,439	31,153	18,252	10,138	8,138	887	357
2017	93,430	58,795	90,843	32,048	17,556	9,829	8,146	897	345
2018	93,526	58,341	91,237	32,896	16,895	9,532	8,097	888	333
2019	93,633	57,921	91,621	33,700	16,857	10,775	8,012	876	360
2020	93,273	57,218	91,694	34,476	16,754	10,985	7,913	862	361

* Actual CEC price track with historical prices used for 1996, 1997, 1998.

Table 5: Coalbed Methane Production Forecast (Reference Technology, CEC Price Track)

Drill Resv. Adds. (Bcf)	Resv. Growth Adds.	Resv. Adds. (Bcf)	Proved Resv.
937	168	1,105	10,564
885	1,136	2,020	11,458
797	292	1,090	11,352
361	282	643	10,810
353	272	624	10,307
378	261	639	9,867
397	251	648	9,485
390	240	630	9,124
413	230	643	8,809
440	219	660	8,546
664	209	873	8,526
648	198	846	8,479
580	188	768	8,355
620	178	798	8,270
599	167	766	8,161
722	157	879	8,174
728	146	874	8,178
730	136	866	8,170
730	125	856	8,149
756	115	871	8,138
790	104	895	8,146
754	94	848	8,097
720	84	804	8,012
703	73	776	7,913
683	63	746	7,797

Table 6: Tight Gas Production Forecast (Reference Technology, CEC Price Track)

Summary Table -- Reference Case

	Tech Recov. Wells	Undev. Resc. (Bcf)	Ult Recov.	Resv. + Prod.	Econ. Undevel. Resour.	Undevel. Wells	Proved Resv. (Bcf)	Prod. (Bcf)
Base Case	355,421	264,867	337,384	72,517	94,929	82,965	34,690	2,743
1997	353,238	264,982	341,773	76,791	93,426	80,482	36,221	2,992
1998	351,269	265,207	345,062	79,856	35,362	24,223	36,294	3,102
1999	352,390	267,825	348,972	81,147	5,995	2,197	34,483	2,997
2000	355,133	272,093	353,941	81,847	7,808	3,193	32,186	2,823
2001	356,535	275,004	357,539	82,534	16,165	6,729	30,050	2,644
2002	357,848	277,709	361,102	83,393	45,760	24,505	28,265	2,507
2003	358,734	279,915	364,617	84,699	60,772	32,346	27,063	2,427
2004	359,435	281,871	368,066	86,196	63,701	33,133	26,133	2,375
2005	360,101	283,694	371,461	87,761	66,080	34,877	25,324	2,337
2006	360,719	285,409	374,778	89,369	76,856	40,974	24,594	2,267
2007	361,088	286,723	378,025	91,302	94,267	60,655	24,260	2,236
2008	361,153	287,742	381,194	93,452	99,402	61,459	24,175	2,230
2009	361,167	288,548	384,281	95,733	100,693	60,840	24,225	2,237
2010	361,182	289,231	387,285	98,054	114,065	63,905	24,310	2,242
2011	361,076	296,481	397,137	100,656	131,484	69,222	24,669	2,272
2012	360,810	296,610	400,022	103,412	135,432	69,509	25,153	2,558
2013	360,548	296,630	402,816	106,186	138,035	69,552	25,369	2,572
2014	360,248	296,395	405,516	109,121	141,552	75,352	25,732	2,601
2015	359,821	295,926	408,117	112,191	148,237	77,080	26,201	2,648
2016	359,267	294,998	410,612	115,614	148,981	76,158	26,976	2,725
2017	357,921	291,891	411,848	119,957	145,243	74,016	28,595	2,872
2018	356,664	288,914	413,084	124,170	142,943	72,401	29,936	2,994
2019	355,457	285,999	414,321	128,322	144,254	77,763	31,094	3,097
2020	352,804	281,949	414,321	132,371	148,677	77,855	32,046	3,180

* Actual CEC price track with historical prices used for 1996, 1997, 1998.

Table 6: Tight Gas Production Forecast (Reference Technology, CEC Price Track)

New Wells	Drill Resv. Adds. (Bcf)	Resv. Growth Adds.	Resv. Adds. (Bcf)	Proved Resv.
2,097	1,831	2,443	4,274	36,221
2,006	1,766	1,299	3,065	36,294
583	667	624	1,291	34,483
55	111	590	701	32,186
73	131	555	686	30,050
162	339	520	859	28,265
588	820	486	1,306	27,063
774	1,046	451	1,497	26,133
808	1,149	416	1,565	25,324
857	1,226	382	1,608	24,594
1,106	1,587	347	1,934	24,260
1,410	1,838	312	2,150	24,175
1,460	2,003	278	2,281	24,225
1,460	2,078	243	2,321	24,310
1,581	2,394	208	2,602	24,669
1,740	2,583	173	2,756	25,153
1,736	2,635	139	2,774	25,369
1,775	2,831	104	2,935	25,732
1,902	3,000	69	3,069	26,201
2,029	3,388	35	3,423	26,976
2,821	4,343	-	4,343	28,595
2,732	4,213	-	4,213	29,936
2,681	4,152	-	4,152	31,094
2,653	4,049	-	4,049	32,046
2,570	3,834	-	3,834	32,699

Table 7: Gas Shale Production Forecast (Reference Technology, CEC Price Track)

Summary Table -- Reference Case

	Tech Recov. Wells	Undev. Resc. (Bcf)	Ult Recov.	Resv. + Prod.	Econ. Undevel. Resour.	Undevel. Wells	Proved Resv. (Bcf)	Prod. (Bcf)
Base Case	210,359	51,104	57,374	6,270	16,823	23,905	3,408	311
1997	209,617	50,995	57,918	6,923	16,543	23,553	3,750	323
1998	208,885	50,891	58,266	7,375	13,031	19,999	3,899	346
1999	208,496	51,034	58,727	7,694	2,800	3,249	3,872	347
2000	209,661	51,766	59,589	7,823	4,597	6,236	3,655	331
2001	209,873	52,014	60,007	7,993	4,694	6,183	3,494	323
2002	210,086	52,257	60,419	8,162	7,324	9,578	3,340	317
2003	210,214	52,460	60,826	8,366	8,720	10,543	3,227	315
2004	210,325	52,632	61,225	8,594	8,810	10,489	3,139	306
2005	210,414	52,781	61,617	8,836	10,429	13,374	3,076	300
2006	210,452	52,900	62,002	9,102	10,477	13,243	3,042	296
2007	210,489	53,006	62,380	9,374	17,163	21,713	3,018	294
2008	210,528	53,105	62,750	9,645	17,436	21,732	2,995	292
2009	210,513	53,166	63,113	9,947	14,474	19,708	3,004	293
2010	210,355	53,165	63,465	10,300	21,893	28,633	3,064	298
2011	210,187	53,137	63,808	10,671	23,244	29,639	3,137	304
2012	210,012	53,098	64,141	11,043	23,509	29,621	3,206	310
2013	209,798	53,021	64,465	11,444	23,740	29,560	3,296	319
2014	209,538	52,913	64,778	11,864	23,947	29,461	3,398	328
2015	209,278	52,793	65,080	12,287	24,146	29,357	3,492	337
2016	208,906	52,590	65,370	12,780	24,269	29,168	3,648	350
2017	208,540	52,217	65,490	13,273	23,846	28,645	3,792	363
2018	208,195	51,857	65,607	13,750	23,437	28,137	3,906	372
2019	207,870	51,510	65,720	14,210	23,041	27,646	3,994	379
2020	207,198	51,090	65,744	14,654	22,621	27,127	4,059	385

* Actual CEC price track with historical prices used for 1996, 1997, 1998.

Table 7: Gas Shale Production Forecast (Reference Technology, CEC Price Track)

New Wells	Drill Resv. Adds. (Bcf)	Resv. Growth Adds.	Resv. Adds. (Bcf)	Proved Resv.
742	363	290	653	3,750
732	358	94	452	3,899
500	224	95	319	3,872
81	37	92	129	3,655
156	82	89	170	3,494
155	84	85	169	3,340
239	122	82	203	3,227
257	149	78	228	3,139
279	167	75	242	3,076
329	194	72	266	3,042
331	204	68	272	3,018
328	207	65	271	2,995
383	240	61	301	3,004
526	296	58	353	3,064
535	316	55	371	3,137
543	321	51	372	3,206
581	353	48	400	3,296
628	376	44	421	3,398
628	382	41	423	3,492
739	455	37	493	3,648
734	459	34	494	3,792
713	446	31	477	3,906
692	433	27	460	3,994
672	420	24	444	4,059
664	426	20	446	4,120

Figure 2: Historical and Projected Unconventional Gas Production - Reference Case

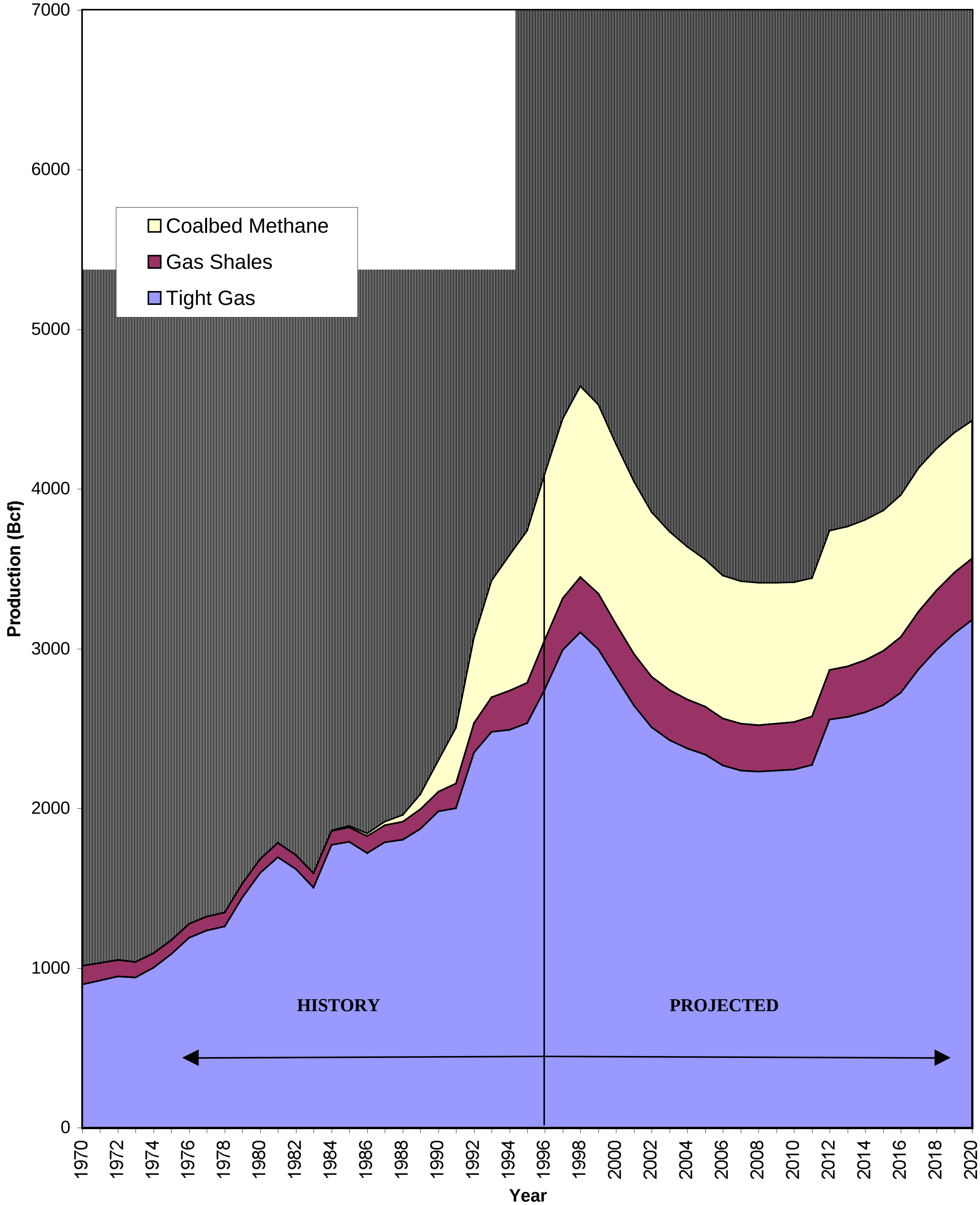
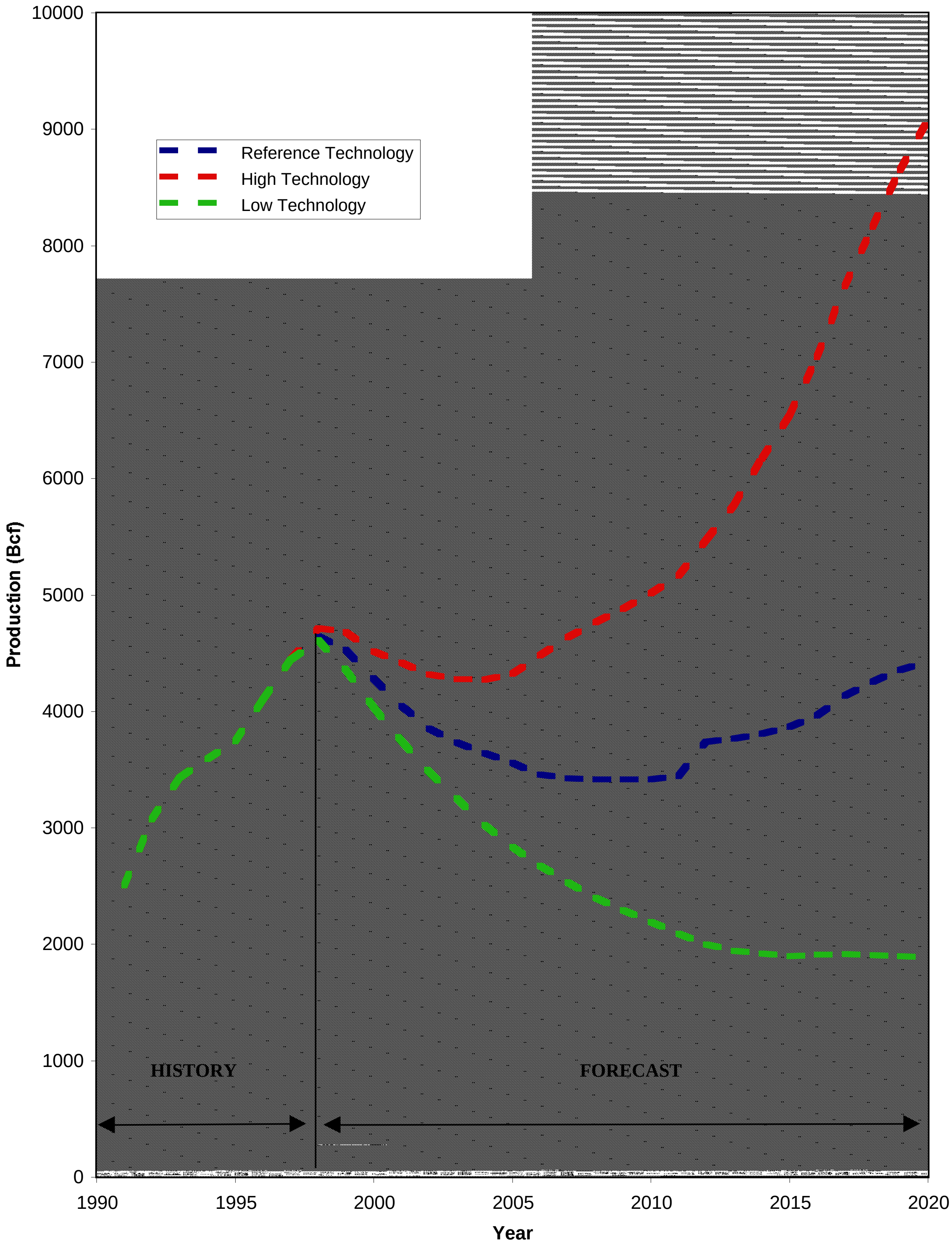


Figure 3: Forecast of Unconventional Gas Production (CEC Price Track)



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